Reservoir simulation for a CO_2 sequestration project

Davood Nowroozi and Donald C. Lawton

ABSTRACT

Time-lapse seismic surveys of a reservoir are an effective way to monitor alterations in the dynamic reservoir parameters and the fluid migration regimen during production or injection. The project is a study of a reservoir under a specified injection plan, using updated geological models in time and space. An existing reservoir model was utilized as the base case. This paper is the initial stage of a larger project; its focus is reservoir simulation. The reservoir was chosen from the Wabamun Area Sequestration Project (WASP). The WASP project was a CO_2 sequestration that was led by the University of Calgary previously.

The target layer for injection is the Nisku aquifer. It is a Devonian carbonate formation with high capacity (porosity) and injectivity (permeability), capped by the Calmar shale. Thes properties make it a suitable medium for CO_2 injection and efficient storage. A geomodel of the project was available. For this research an injection plan was defined with ten wells and constant bottom-hole injection pressure. The behavior of the reservoir was simulated for 50 years of injection and a further 50 years for prediction of the CO_2 plume shape and pressure changes in the reservoir.

After 50 years injection with constant bottom-hole pressure, the CO_2 plume only covered approximately 10% of the top layer of the Nisku aquifer of the geomodel area, but pressure changes occurred over the entire reservoir. At 50 years after injection termination, the mass of the plumes did not change meaningfully but pressure equalized across the entire reservoir. The defined plan can store 25% of the expected total CO_2 locally available for sequestration (20 Mt/year).

INTRODUCTION

This paper is the initial stage of a research project for geophysical monitoring of a real reservoir with injection/production effects on dynamic parameters that may yield a change in seismic response. Geophysical parameters change with reservoir fluid properties and geomechanical changes by injection/production in the reservoir. Collapse or dilation in reservoir layers within the seismic resolution range can be detectable by traditional seismic methods. The development of new joints and fractures or the propagation of the old ones, are other aspects of production/injection that can be mapped via microseismic methods.

WASP is a project that was conducted in 2008-2009 by the University of Calgary, and existing data are suitable for simulation and geophysical monitoring goals. Results of this study are dynamic reservoir variable (fluid properties) which simulated in time and space inside the reservoir to estimate storage capacity.

The Wabamun project area is located in southwest of Edmonton (Figure 1) and covers 5034 km^2. There are four coal-burning power plants in northern part of area and these annually emit 11 billion sm^3 of CO_2.

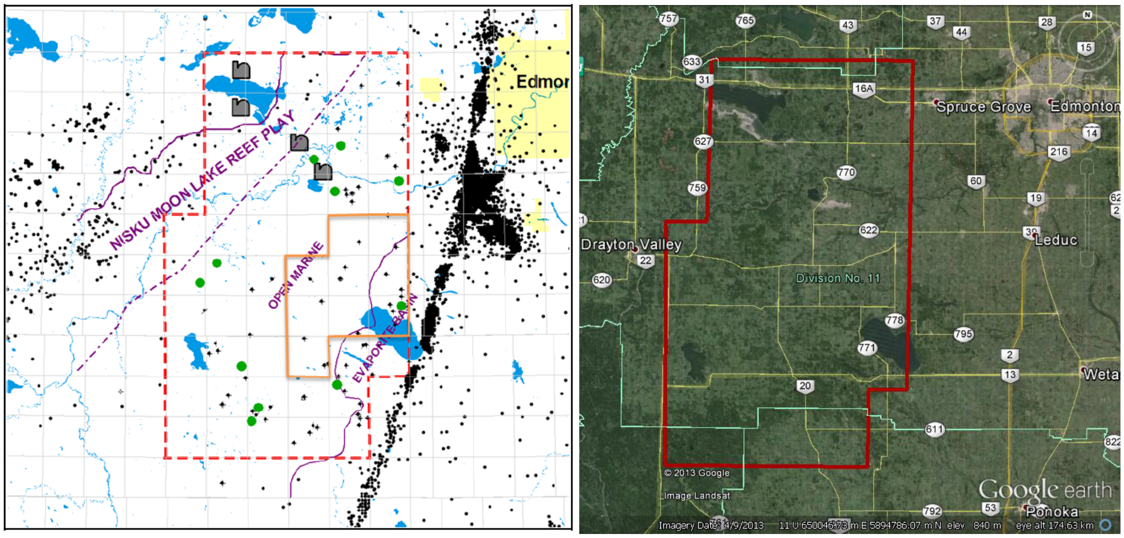

FIG.1. Map and satellite image of WASP study area. Gray factory shapes indicate coal-burning Power plants in the map.

Considering the amount of CO_2 produced by the power plants, the desired capacity for CO_2 sequestration is equal to the production or one GT (550 billion sm^3) over 50 years. The current paper is about simulation for CO_2 injection and using the best simulator for an injection schedule.

GEOLOGY

The selected area for injection process is in the central plains where the surface is covered by young quaternary glacial sediments and under which lie strata of the Paskapoo, the Scollard and the Horseshoe Canyon formations (Figure 4).

The target layer, the Nisku Formation, is a porous medium with a saline aquifer that is capped by the Calmar Formation, and these conditions make a suitable reservoir for CO_2 injection and storage. Depth of this formation in the project area is 825 to 1810 m. The Nisku and Calmar are members of the Winterburn Group in northeastern and central Alberta (Belyea, 1964) and in this area, the Nisku is underlain by the Ireton and Leduc formations. It represents carbonate sedimentation of upper Devonian age in the Frasnian stage (Figure 2 and Figure 3). The lithology of the Nisku Formation is crystalline dolomite, dolomitic siltstone, green shale, anhydrite with a thickness between 40 to 60 m to greater than 100 m in western Alberta.

In the Wasp area, the Nisku Formation has a gentle dip that is less than one degree (depth in the north is 850 m and in the south it reaches a depth of 1800m over 100 km).

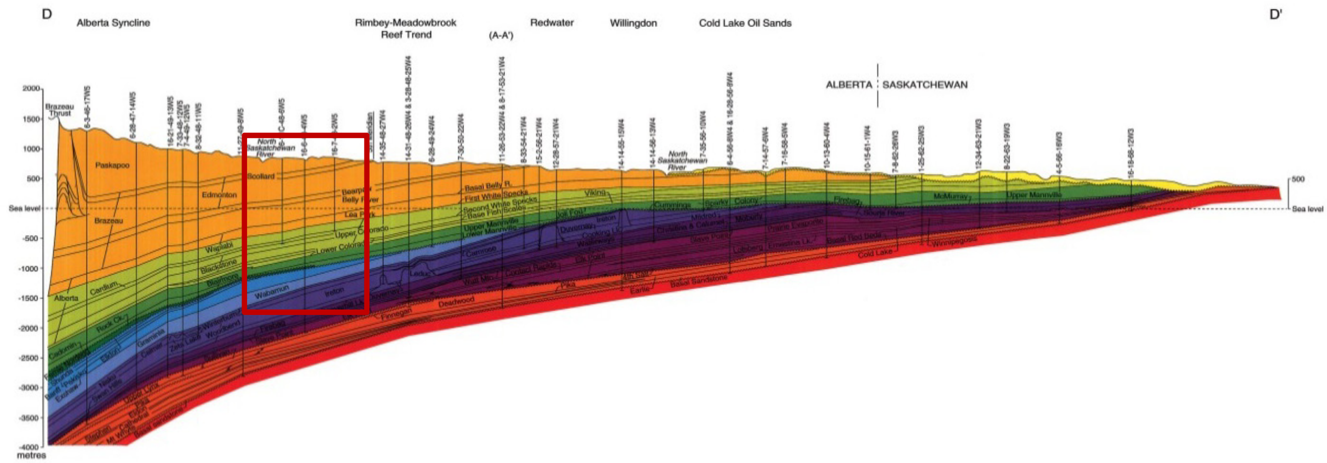

FIG.2. Geologic cross-section of the Western Canada Sedimentary Basin (Wright et al., 1994), the red rectangular shows project area and stratigraphy

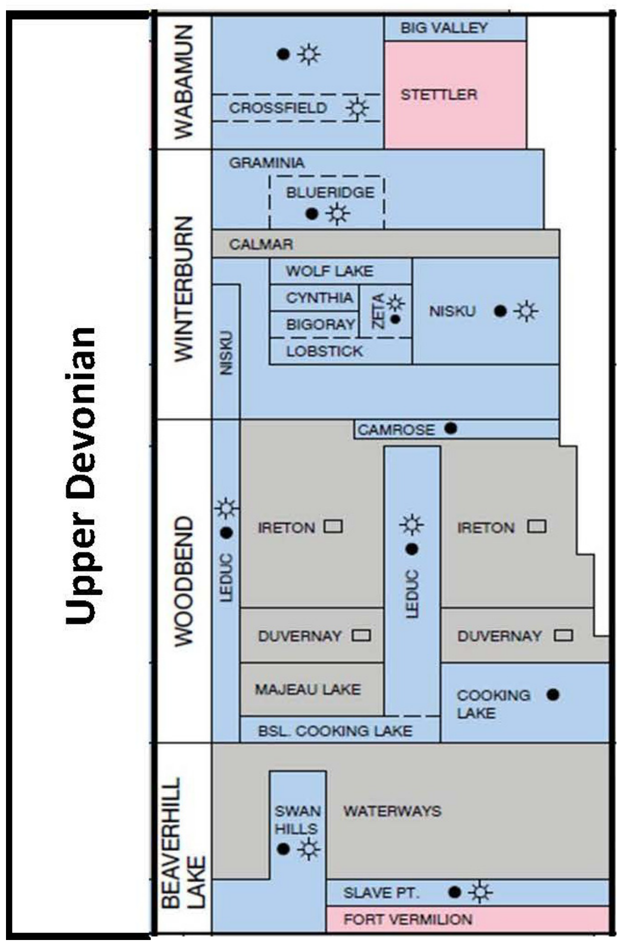

FIG.3. Stratigraphic chart of the Upper Devonian in the central plains

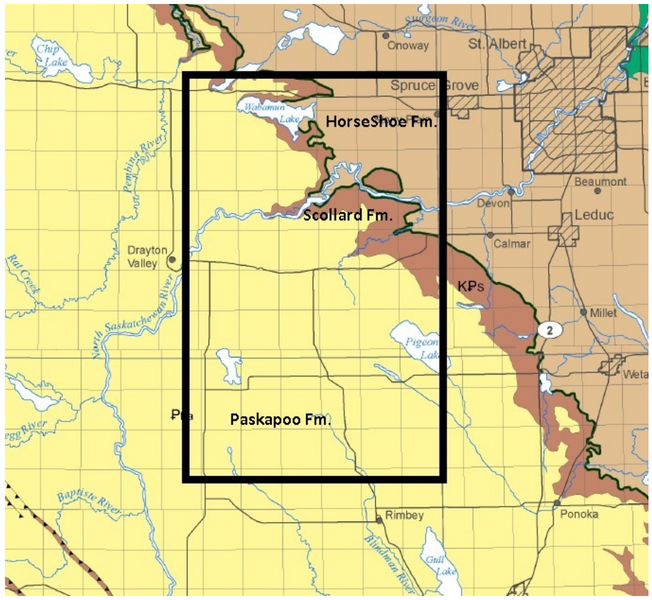

FIG.4. Bedrock in project area

CO_2 TRAPPING MECHANISM IN AN AQUIFER

Four mechanisms help to trap CO_2 in an aquifer:

1- Stratigraphic and structural trapping

2- Residual Trapping

3- Solubility Trapping

4- Mineral Trapping

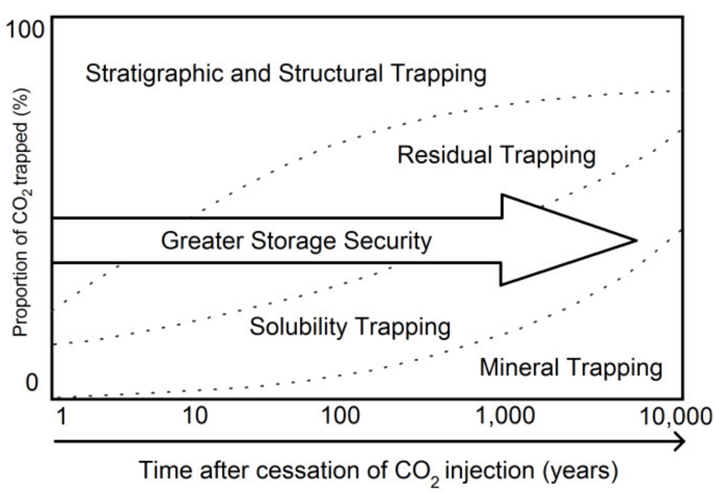

FIG.5. CO_2 trapping mechanisms and increasing CO_2 storage security over time (Class et al., 2009; IPCC, 2005).

According to the trapping mechanism and storage stage (Figure 5) in the first years of injection, structural and stratigraphic trapping play the main role, but after centuries, mineral trapping and solubility trapping are most important and thus CO_2 storage in aquifers is most secure after this time.

SIMULATION

Reservoir simulation is a direct numerical modelling method to model fluid flow in a reservoir or in a better description in the porous medium. One use of simulation is for managing and optimizing the production/recovery (in this study injection) rate, and reduction in production/injection cost.

Some equations are used in hydrocarbon simulation that the continuity equation is a main base. The conservation law in reservoir (conservation of mass, energy and momentum) is essential for mass balance and the continuity equation. In simple form, for each cell a combination of Darcy's law (equation 1), the material balance (equations 2 and 3) and flow equation (equation 4) are solved.

Darcy's law:

$$\mathbf{q} = -\frac{\mathbf{k}}{\boldsymbol{\mu}}\nabla\mathbf{P} \tag{1}$$

Material Balance:

Mass flux =Accumulation + injection/production

$$-\frac{\partial J_x}{\partial x} - \frac{\partial J_y}{\partial y} - \frac{\partial J_z}{\partial z} - q = \frac{\partial C_l}{\partial t} \tag{2}$$

or:

$$-\nabla . \boldsymbol{M} = \frac{\partial}{\partial t}(\emptyset \rho) + \frac{Q}{\rho} \tag{3}$$

and simulator flow equation:

$$\nabla . [\lambda(\nabla P - \gamma \nabla z)] = \frac{\partial}{\partial t}\left(\frac{\emptyset}{\beta}\right) + \frac{Q}{\rho} \tag{4}$$

$$\lambda = k/\mu\beta \tag{5}$$

Black-oil and Compositional simulators are two approaches for reservoir simulation. The Black-oil simulator that is used in this paper (after tuning in PVT table), is suitable for three components (oil, gas and water) and three phases that their properties are function of pressure. It is usable for cases with recovery mechanics not sensitive to composition changes in the reservoir fluids such as primary recovery, solution gas drive, gravity, drainage, gas cap expansion, water drive, water injection and gas injection without mass transfer. The main assumes in the Black oil simulation are:

1- Darcy's law governs the velocities of the fluids.

2- The void porous is filled by water/oil and gas

3- Capillary pressure = gas pressure – oil pressure

4- Phase mobility = phase permeability / phase viscosity

A Compositional simulator can support multi-component and multi-phase reservoirs based on equation of state (EOS) modeling that may include new components created because of chemical reactions as miscible gas injection. The Compositional method is expensive and takes more time comparing with Black Oil Simulator.

For a Black Oil simulation, the parameters that are needed are (a) geometry and (b) matrix properties, (c) fluid property and (d) well production/injection. Geometry and properties are input into grids and cells with size and static properties of each of them (for example porosity). Other components are fluid properties that cover phase viscosities, solution gas-fluid (here water) ratio (R_s) and relative permeability. Th production/injection schedule for the wells is the final part to complete, as the effect of production or injection will enter to simulation as our last term of material balance or simulator flow equations.

SIMULATION OF WASP AREA

Selecting a suitable simulator

As mentioned above, CO_2 and water can make a new phase because of the solubility of CO_2 in water, so the presence of new phase, forces us to use a compositional simulator. However, processing time and the high cost of the compositional method encourage reservoir modellers to use an algorithm for using black-oil simulation with tuning on PVT data, as developed by Hassanzadeh and et al., (2008).

For the current project, with tuning applied to the parameters (for density and viscosity) it is possible to use Black-oil method for CO_2 injection in saline water. Table 1 shows base properties to run the simulation.

Table 1: Reservoir base properties

Depth (m)	**1860**
Thickness (m)	**70**
Pressure at aquifer top (Mpa)	**16**
Temperature (^{O}C)	**60**
Permeability (md)	**6.2-400**
Vertical anisotropy	**0.27**
Porosity (%)	**6 to 12**
Salinity of formation water (mg/l)	**190000**
Density of formation water (kg/m^3)	**1155.5**
Viscosity of formation water (mPa.s)	**840**

Geometry and Geomodel

The WASP area covers about 5034 km^2 and the Nisku aquifer is the final target for produced CO_2. For gridding purposes, surface of the Nisku aquifer was divided to 500x500 m grids and vertically to 30 unequal levels, which in all made more than seven hundred thousand cells (122x193x30).

For make a geomodel of the aquifer, data from 79 well log, 13 core data, 199 2D seismic lines, mineralogy data, and twenty two drill stem tests (DST) were main sources (Eisinger et al. , 2009). Figures 6 and 7 demonstrate Porosity and permeability (in x, y and z direction) from geomodel data in the top horizon. In the Nisku formation, vertical permeability is lower than horizontal permeability.

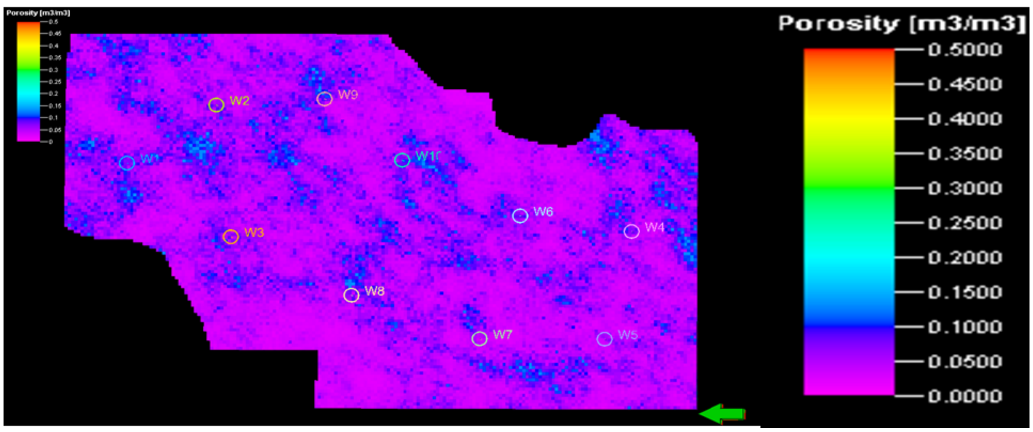

FIG.6. Porosity map for the first layer

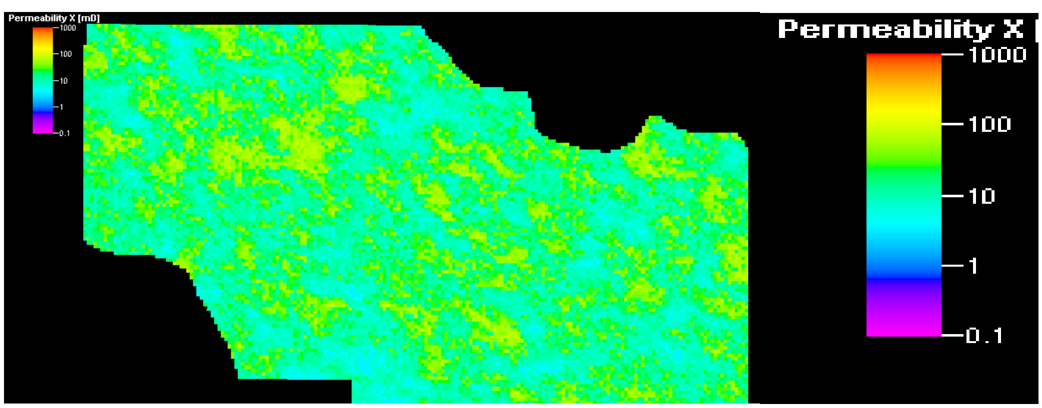

FIG.7a. Permeability (horizontal) for the first layer.

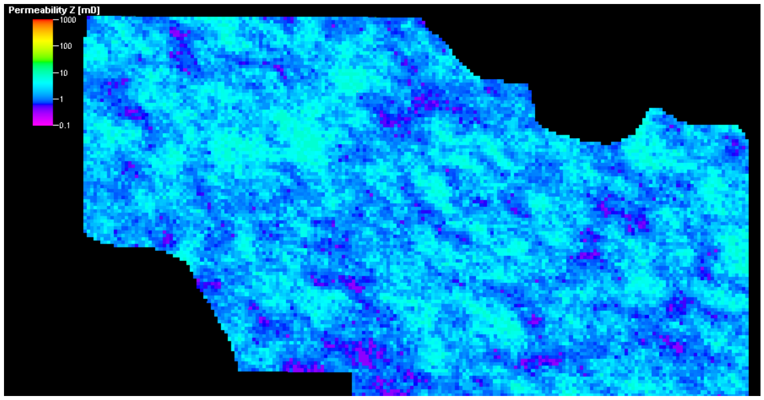

FIG.7b. Permeability (vertical) for the first layer.

Relative Permeability

The relative permeability function is a parameter that is input to the simulator in order to conduct the numerical simulations of two-phase fluid flow. This function is extracted from permeability parameters for two phases. It is a function of phase's saturation and can calculate by normalizing of the effective permeability by the absolute permeability value. Obviously, the effective permeability in the presence of just one phase is equal absolute permeability. For these calculations, the relative permeability data for the aquifer in the WASP area from Bennion and Bachu (2005) were used (Figure 8).

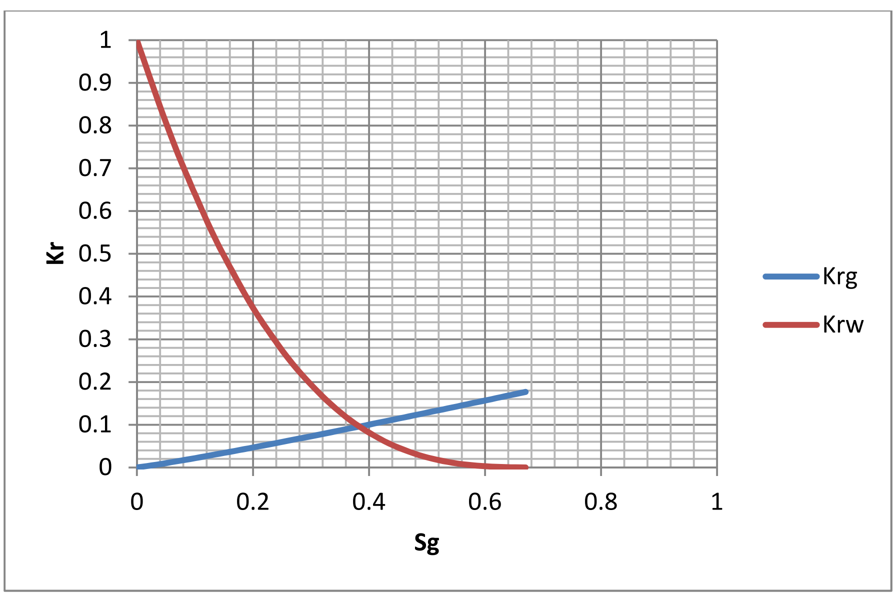

Fig.8. Gas-Water relative permeability diagram for the Nisku acquifer (WASP area).Sg, Krg and Krw are gas saturation and relative permeability for gas and water.

Injection schedule

This model has ten injection wells that are parallel to the two sides of the area with a NE to SW trend. All 30 horizons of aquifer are open to injection in wells and the well bottom pressure was held constant at 40 MPa. The injection was scheduled for 50 years and after that, simulation was continued for another 50 years for the prediction of plume movement and the fate of the pressure in the reservoir.

Constant well bottom pressure is considered for CO_2 injection, because leakage of this gas is a concern in CO_2 sequestration projects, and constant volume injection plan can increase well bottom pressure after initial years of injection and high pressure can make new fractures (as fracking procedure) in the cap layer and may cause gas leakage.

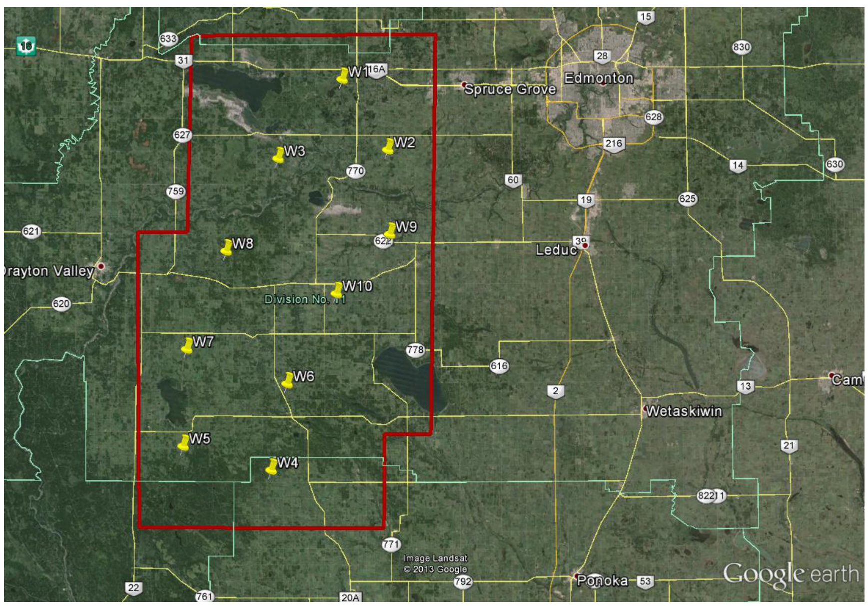

FIG. 9. Satellite image of the WASP area. The yellow points show possible injection wells

Simulation Results

In this section, the capacity of the field and for each well individually, and dynamic parameters after CO_2 injection are demonstrated. The focus on the simulation was on parameters that can effect on seismic responses and briefly, they are capacity, water and gas saturation and pressure.

In this step, matrices of dynamic parameters are made in time steps for the entire population of cells that will be useful later for the geophysical modeling stage.

Capacity

For ten wells and a schedule for injection for 50 years and well bottom pressure equal to 40 MPa, the total capacity of the field is about 132 billion cubic meters (at 15 Celsius degree and 101.325 kPa).This volume is about 25% of the expected total CO_2 locally available for sequestration. Table 2 shows the capacity of the reservoir and for each well individually.

The result of simulation shows that wells W8 and W3 have the highest and lowest capability for CO_2 injectivity and storage capability, respectively. Well W8 is about three times more efficient than W3 due to permeability and porosity distribution. For increasing injection capacity, more injection wells or using horizontal wells in reservoir layer are possible, but new injection plans with more wells or horizontal shaft would cost more. Since the main goal of this research is geophysical monitoring, in this paper one plan is simulated.

Table 2: Volume of CO_2 injected in each well

Well	**Cumulative injection(Billion sm^3)**	**Portion of each well (%)**
Total Field	131.9291	100.0
W1	17.4438	13.2
W2	12.4713	9.5
W3	6.4986	4.9
W4	10.5579	8.0
W5	14.6867	11.1
W6	8.2861	6.3
W7	10.8618	8.2
W8	22.2886	16.9
W9	12.4358	9.4
W10	16.3986	12.4

As mentioned before, one of the trapping mechanisms in aquifers is gas dissolution in water, and this is estimated in the simulation. Figure 10 shows total capacity , free gas and solution gas volume over the injection history. As we expect, the fraction of solution gas increases during injection. Fig.11 shows the injection capacity of each well.

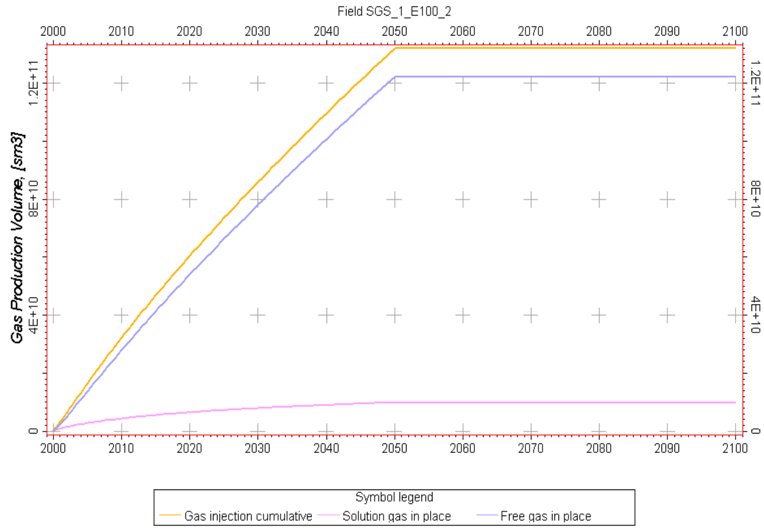

FIG.10. Total gas injection volume and fraction of free gas and solution gas.

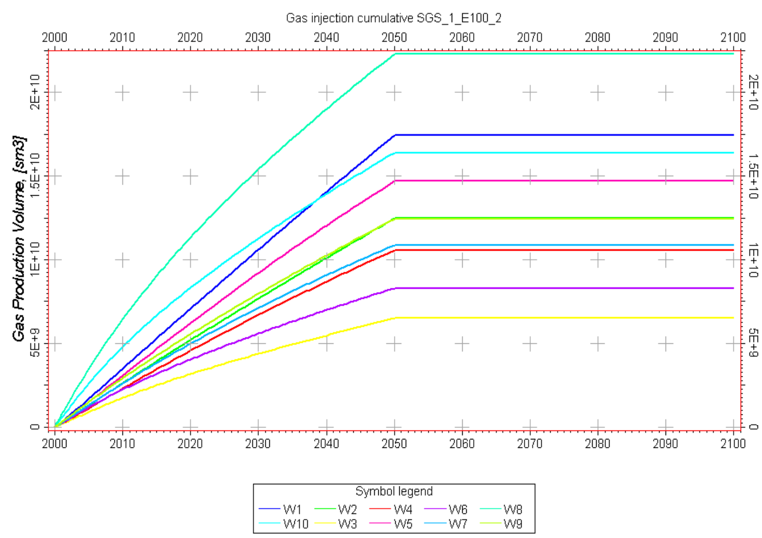

FIG.11. Comparing injection capacity for each well

Water and Gas saturation during and after injection

The CO_2 gas distribution and saturation maps and simulation results show that the CO_2 plume close to each well during and after injection, and there is no important inter-well transmission into the field. The plume shape at each well is a function of permeability in the horizontal and vertical directions. The surface area of the plumes is between 25 to 65 km^2. Considering the average coverage for each well to be 45 km^2, it would be possible to drill new wells for CO_2 storage, except that the problem for storage with a high number of wells is the pressure in the reservoir that can limit injection within just the first few years (refer to the diagram of gas flow for WASP, figures 19 and 20).

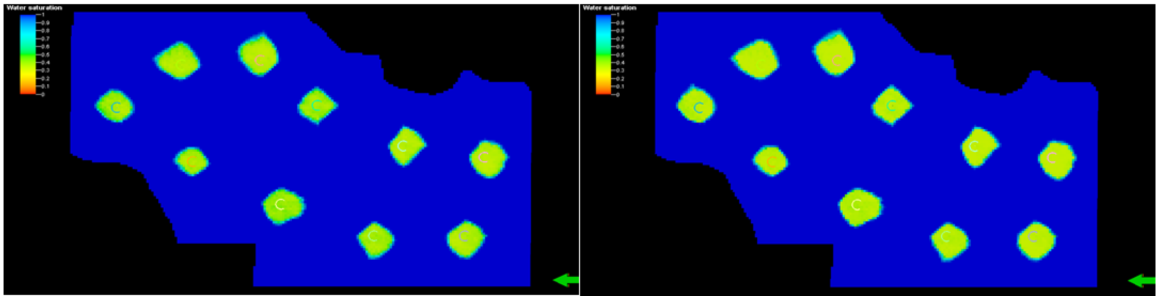

FIG.12. Water saturation after 50 and 100 years (saturation from 0 to 1)

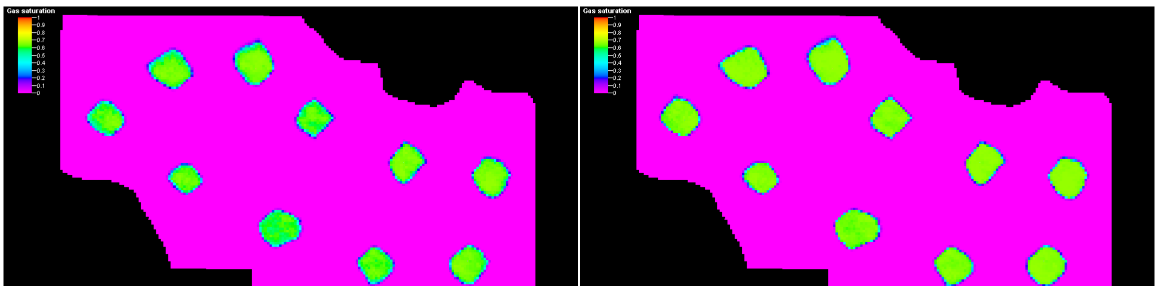

FIG.13. Gas saturation after 50 years injection (left); and 100 years from beginning or 50 years after stopping CO_2 injection (right).

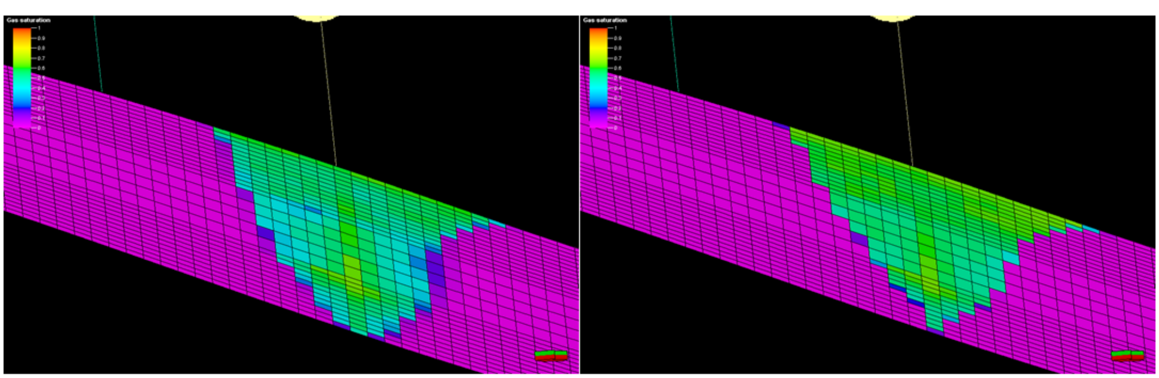

FIG.14. Gas saturation in well No. 8 (vertical section) after 50 years of injection (left); long term fate of CO_2 after 50 years after stopping injection or 100 years after beginning injection (right).

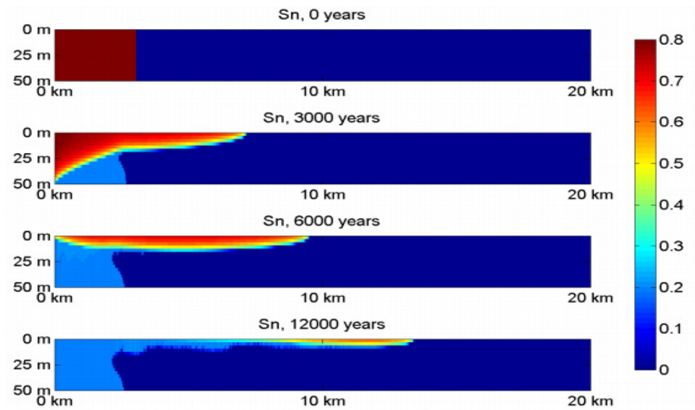

FIG.15. Gas saturation with dissolution in the long term (0 to 12000 years) (Elenius,M.L., et al., 2010)

Pressure

The pressure in each cell of the reservoir in the long term is a function of the injected gas volume, the reservoir size and permeability. This dynamic parameter can be calculated during the reservoir simulation by solving material balance equation. Also the pressure can control gas-water rate in the reservoir (Figure 16), that is the main mathematical base for calculating the solution gas volume shown in Figure 10.

For the Nisku aquifer as a reservoir, in the first years of injection, the pressure distribution is mainly around the injection wells. Figure 17 illustrates the pressure distribution in the reservoir after two years of injection. However, after 25 years it is completely distributed in the reservoir as it is shown in the top left part of Figure 17. After 50 years when injection stops, the pressure distribution seems constant and equalized across the entire reservoir (Figure 17 bottom left).

Figure 18 shows constant well bottom pressure during 50 years of injection and after injection termination, it is falls to near the reservoir average pressure. Finally gas injection flow rate as a function of permeability and pressure, is calculated in the simulation, as shown in Figures 19 and 20.

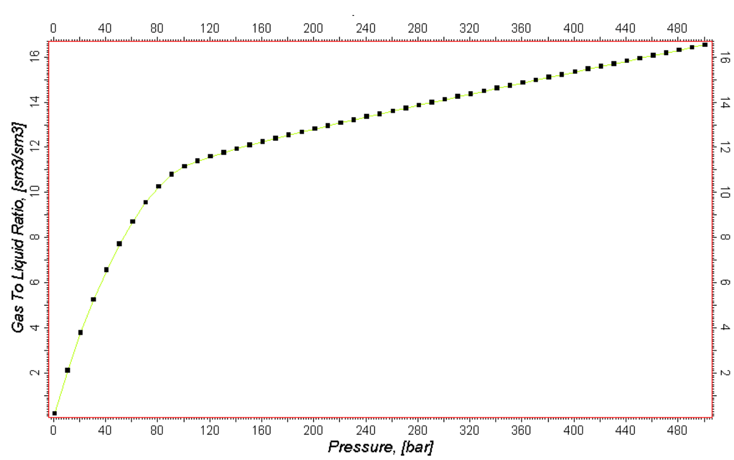

FIG.16. Gas to water ratio for WASP field with changing pressure.

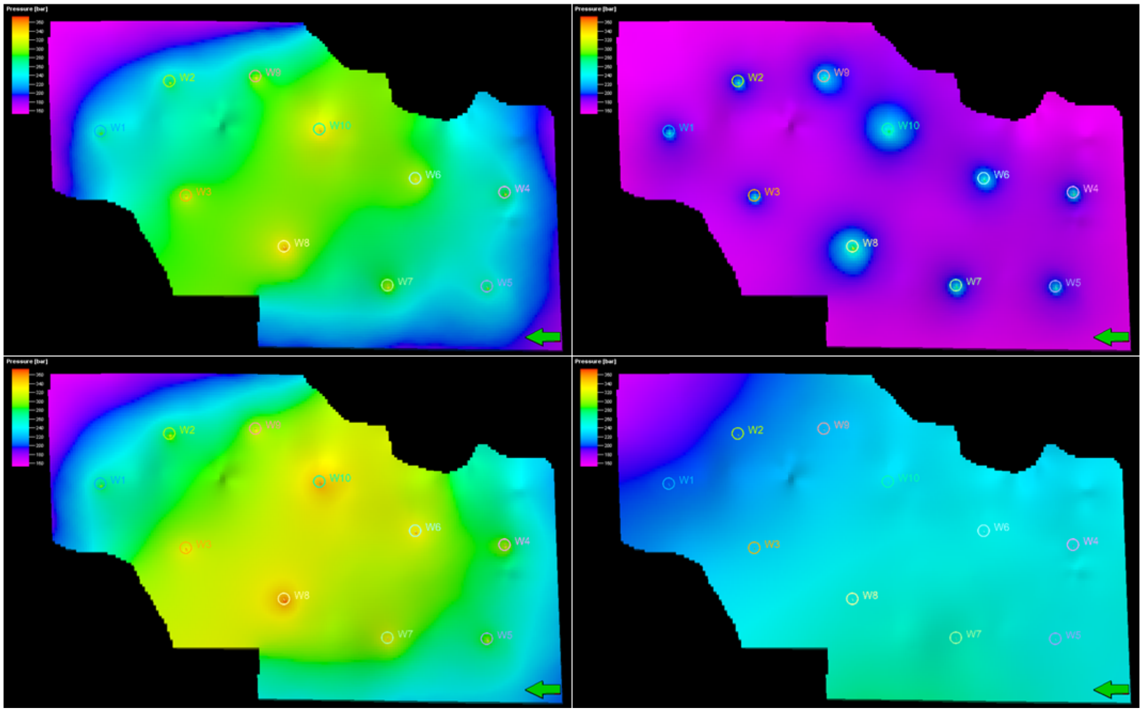

FIG.17. Pressure in the second (upper right), 25th (upper left), 50th (lower left) and after 100 years of injection (lower right)

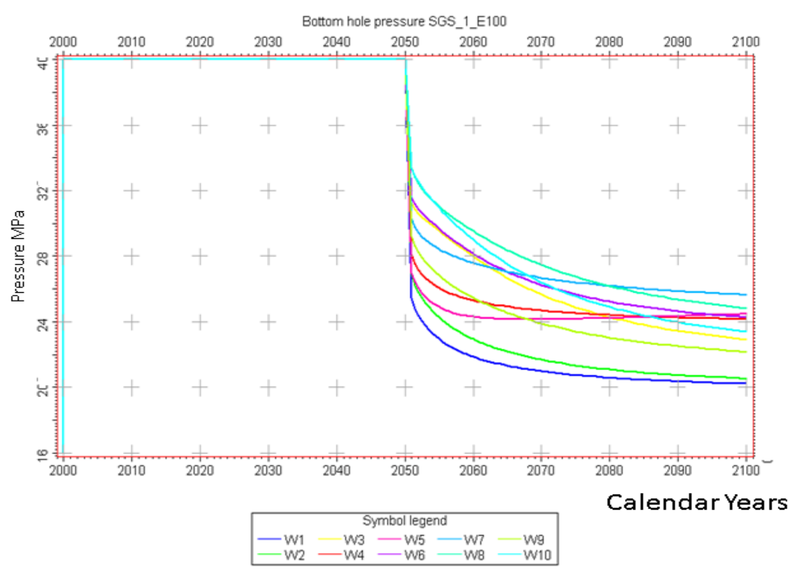

FIG.18. Residual pressure after injection. For all wells, the well bottom pressure is constant (40 MPa) during injection, the change in bottom pressure after discontinuing injection is a function of permeability and porosity around wells.

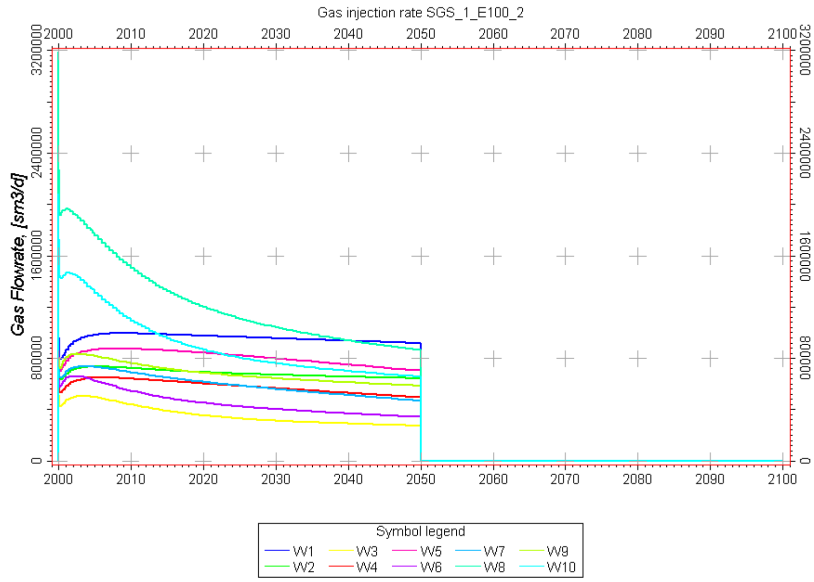

FIG.19. Gas flow rate for wells, Horizontal axis shows calendar years

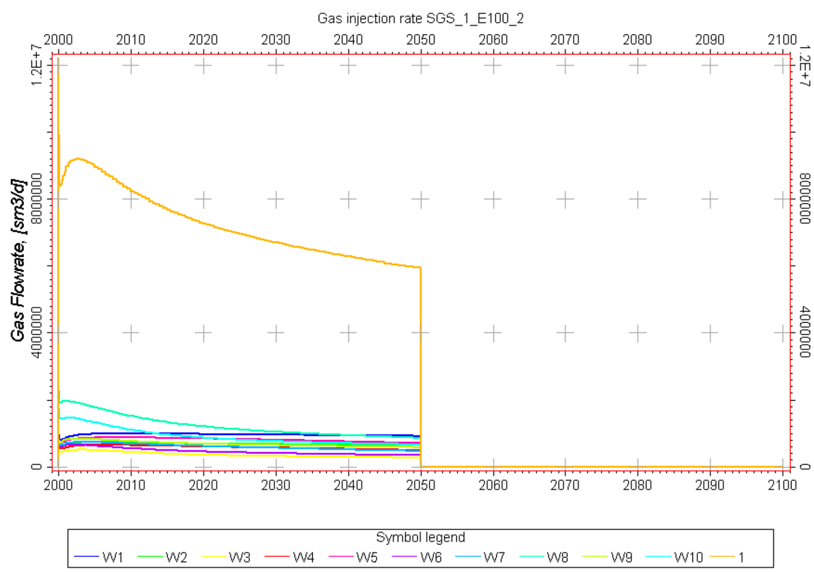

FIG.20. Total gas flow for WASP, in the first months of injection, the gas flow rate is high but falls down immediately.During long-term injection, the flow rate decreases gently.

CONCLUSIONS

The injection make a funnel shape of gas around wells shaft that radius of gas distribution is various from 1700 m to 6000 m in the top horizon of aquifer, so there is no interference between the gas plumes. In the average estimation, each well involves 45 km^2 an average for a 50 year injection, up to 100 wells can inject CO_2 without any interference between their plums in this aquifer, but should consider reservoirs pressure change and limitations.

The capacity of each well is change by the medium's porosity and permeability around each well and changes from 6 to 22 billion sm^3. The total capacity of the field in the present model is about 132 billion sm^3 that just covers about 25 percent of the storage expectance.

Continuing the simulation for thousands years, the injected CO_2 to form a gas cap under the seal layer (the Calmar formation) in the top horizon of the Nisku. This effect can be important for the long term geophysical monitoring.

In the next stage, geophysical model for each cell will be created during injection and it will expand for the reservoir and will describe our expectance of time lapse observing, also this research has a glance at geomechanical changes in reservoir and effects.

ACKNOWLEDGMENTS

We would like to thank Dr. H.Hassanzadeh and Dr. S.A.Ghaderi for help with the simulation, and Schlumberger for the use of Petrel and ECLIPSE and Dr. R.Maier for computer support. We would also like to thank CREWES Sponsors for their support.

REFERENCES

Bennion,B., Bachu, S., 2005, Relative permeability characteristics for supercritical CO2 displacing water in a variety of potential sequestration zones in the western Canada sedimentary basin, Paper SPE 95547 at SPE Annual Technical Conference an Exhibition, Dallas, TX, p. 9–12

Devonian lithofacies and reservoir styles in Alberta, 1987, Second international symposium on the Devonian system, Calgary

ECLIPSE Blackoil reservoir simulation-Training and exercise guide V2, 2009, Schlumberger

Elenius,M.L., Tchelepi,H.A. , Johannsen,K., 2010, CO2 trapping in sloping aquifers: high resolution numerical simulations , XVIII International Conference on Water Resources, Barcelona

Eisinger, C.L., Jensen, J.L., 2009, Geology and Geomodelling, Wabamun area CO2 sequestration project (WASP), University of Calgary

Fanchi, J.R., 2006, Principle of applied reservoir simulation, Elsevier

Ghaderi,S. ,Leonenko,Y. , 2009, Reservoir modelling ,Wabamun Area CO_2 sequestration project (WASP), University of Calgary

Hassanzadeh,H., Pooladi-Darvish, M. , Elsharkawy A. M., Keith, W. K. ,2008 ,Predicting PVT data for CO_2-brine mixtures for black-oil simulation of CO_2 geological storage, International Journal of Greenhouse Gas Control 2 ,P65-77

Pooladi-Darvish, M., 2009, Geological storage of CO2, Part 2: Reservoir engineering aspects, Technical video series, Fekete